Wholesale Power Price Forecast

Current Trends Forecast

Jeff King

Power Committee

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What is the power price forecast?

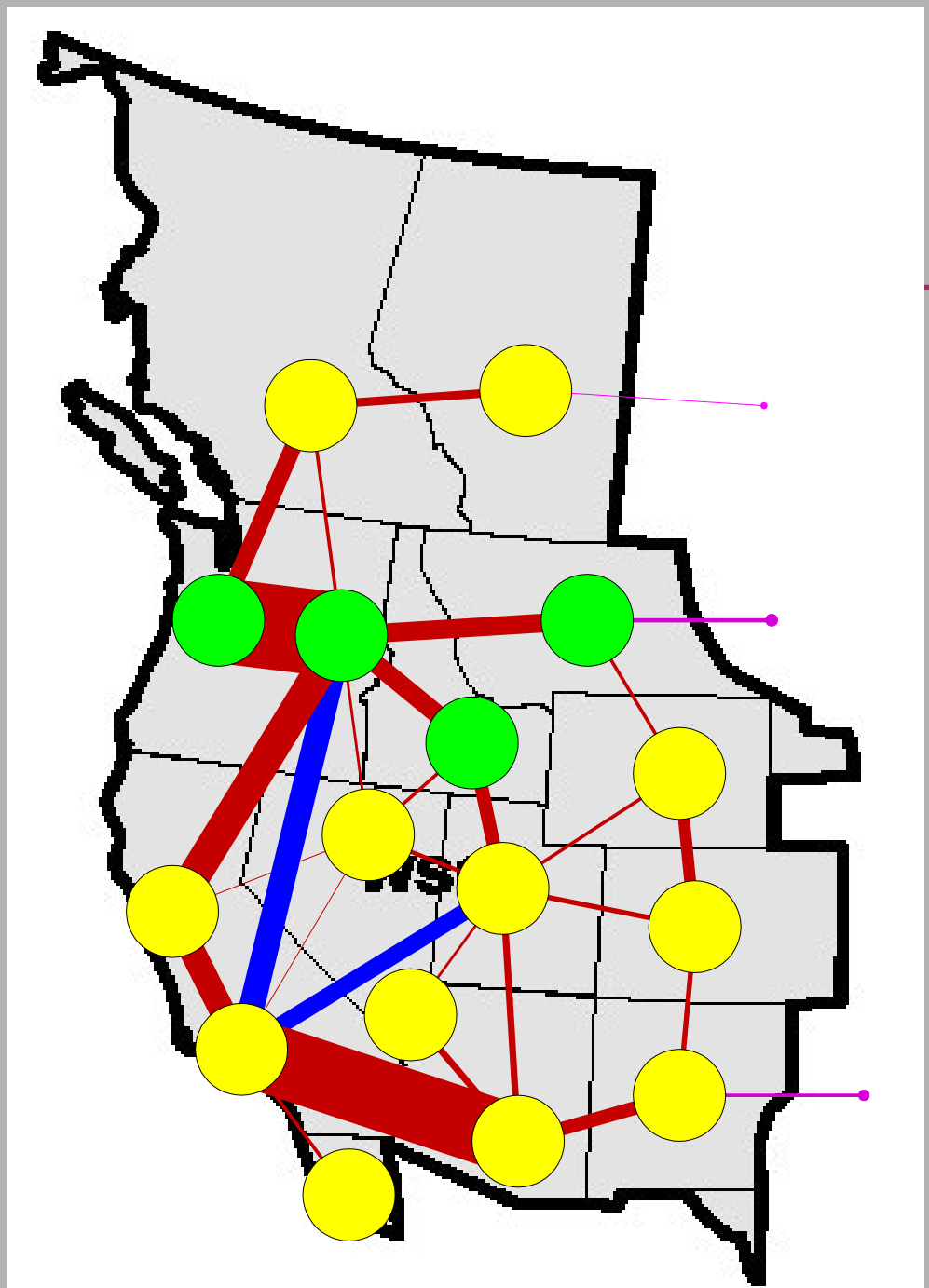
- An estimate of future wholesale spot market power prices.
- E.g., as would be traded as short-term contracts at the Mid-Columbia trading hub.
- 2001 to 2020 (will be extended to 2025).
- Monthly and annual average prices for high & low-load hours (can also look at hourly prices).
- Ancillary product is a forecast of market-driven future generating capacity additions.

Why do a power price forecast?

- Estimate the market value of new resource alternatives (e.g., conservation measures).
- Estimate the cost implications of policies affecting power system composition and operation (e.g., value of a seasonal shift in hydro output).
- Estimate certain environmental effects of changes in power system operation (e.g., effect of resource additions on CO2 production).

How is the forecast made?

- AURORA© Electric Market Model
- A proprietary computer model of the western (WECC) power system.
- Vendor: EPIS of West Linn

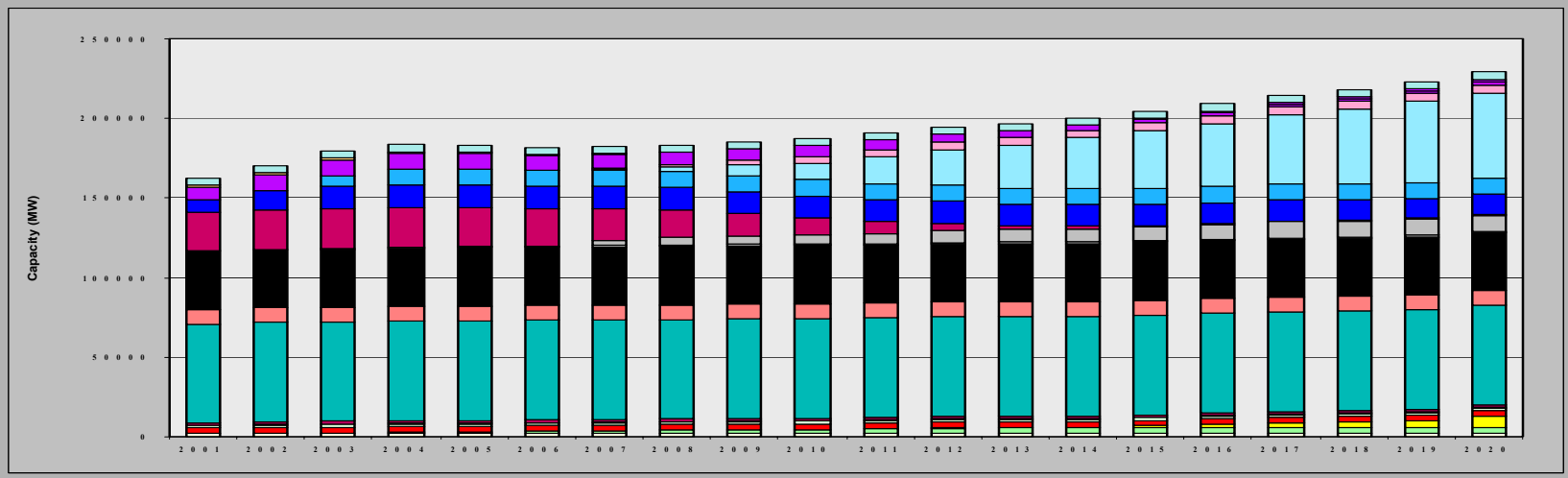


Load-Resource Areas

- Defined by transmission bottlenecks
- individual generating units (>3700 total)
- fuel price forecasts for ea.
- load forecast for ea.
- load curtailment blocks for ea.
- new resource options for ea.

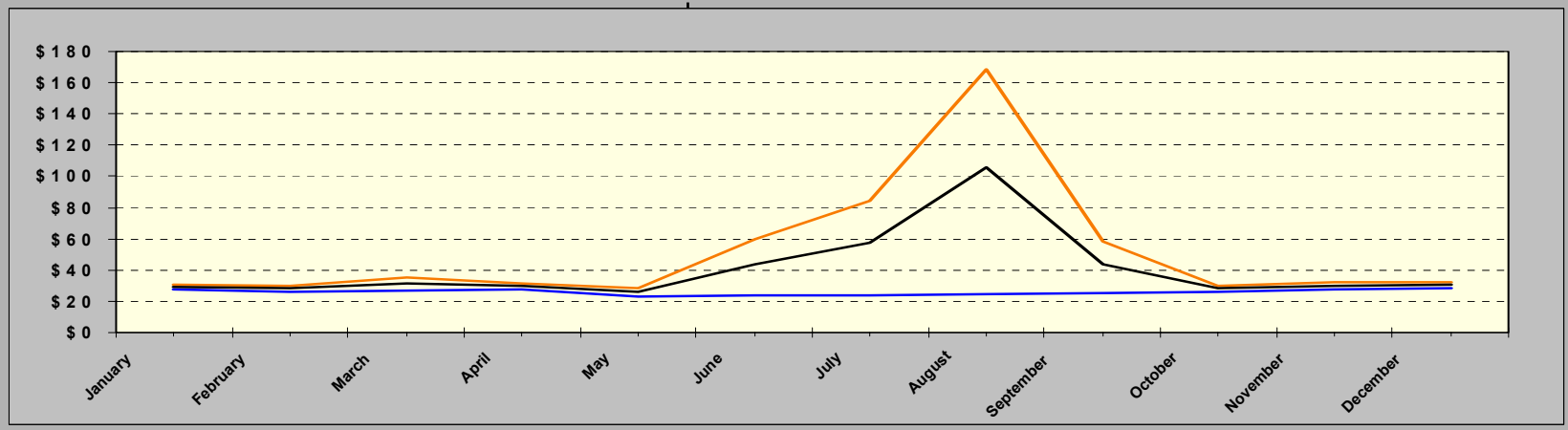
Step 1: Forecast future resource mix

- A series of iterative model runs (30 – 60) with resource cost-effectiveness testing.
- Plants having uneconomic going forward costs are retired.
- New units having positive net present value are added.
- Model seeks a least-cost resource mix.



Step 2: Forecast prices for selected hours

- Hourly market clearing prices are calculated for each load-resource area.
- Hourly area price = variable cost + dispatch premium of most expensive unit required to meet load for that hour in that area.
  - May be a unit within another area (import).
  - May be load curtailment (if no units available, or if cost-effective)



General assumptions

- Projects under construction are completed as scheduled; additional projects are market-driven.
- Suspended projects:
  - If > 25% complete, entered as partial-cost new resource options.
  - If < 25% complete, omitted
- New projects are developed by resource-specific mix of developers.
- Projects scheduled for retirement are retired; additional retirements are market-driven.

More general assumptions

- Most units carry an intra-regional transmission cost:
  - $15/kW/yr point-to-point transmission & basic ancillary services cost plus 1.9% transmission loss penalty.
  - Exceptions include peaking units and industrial cogeneration
- Pancaked inter-area transmission losses & rates.
- Bid margin set at 5% of variable cost.

Significance of the "Current Trends" Case

- Our best estimate of future wholesale power prices resulting from continuation of current economic and energy policy trends.
  - Average water conditions
  - Average loads
- Not necessarily the "Right thing to do"
  - e.g., may not fully consider value of risk mitigation.
- Not intended to represent a recommended course of action

Current Trends (Base) case assumptions

- NPPC draft medium fuel price forecasts.
- NPPC draft medium load forecasts:
  - Demand returns to medium growth rates by 2006.
  - Long-term growth adjusted for programmatic conservation.
- New resource options:
  - Gas-fired combined-cycle GT
  - Duct firing for above
  - Gas-fired simple-cycle GT
  - Wind
  - Pulverized coal-fired steam-electric
  - Solar PV
- Permanent 1.7 cents/kWh production incentive for new wind & solar.

More Current Trends case assumptions

- SBC and RPS resource development forced in:
  - simulated as new wind.
  - quantity based on price forecast/cost difference
- Oregon CO2 standards for all new fossil units:
  - CO2 offset fee, as a variable cost, $1/TCO2 escalating 20%/yr.
  - Fee applies to 17% of total CO2 production.
- New renewables receive $7.50/MWh green tag credit.
- Intermittent resources limited to 15% of total resources, by area (approximate).
- No new coal in Western WA, W. OR, CA.

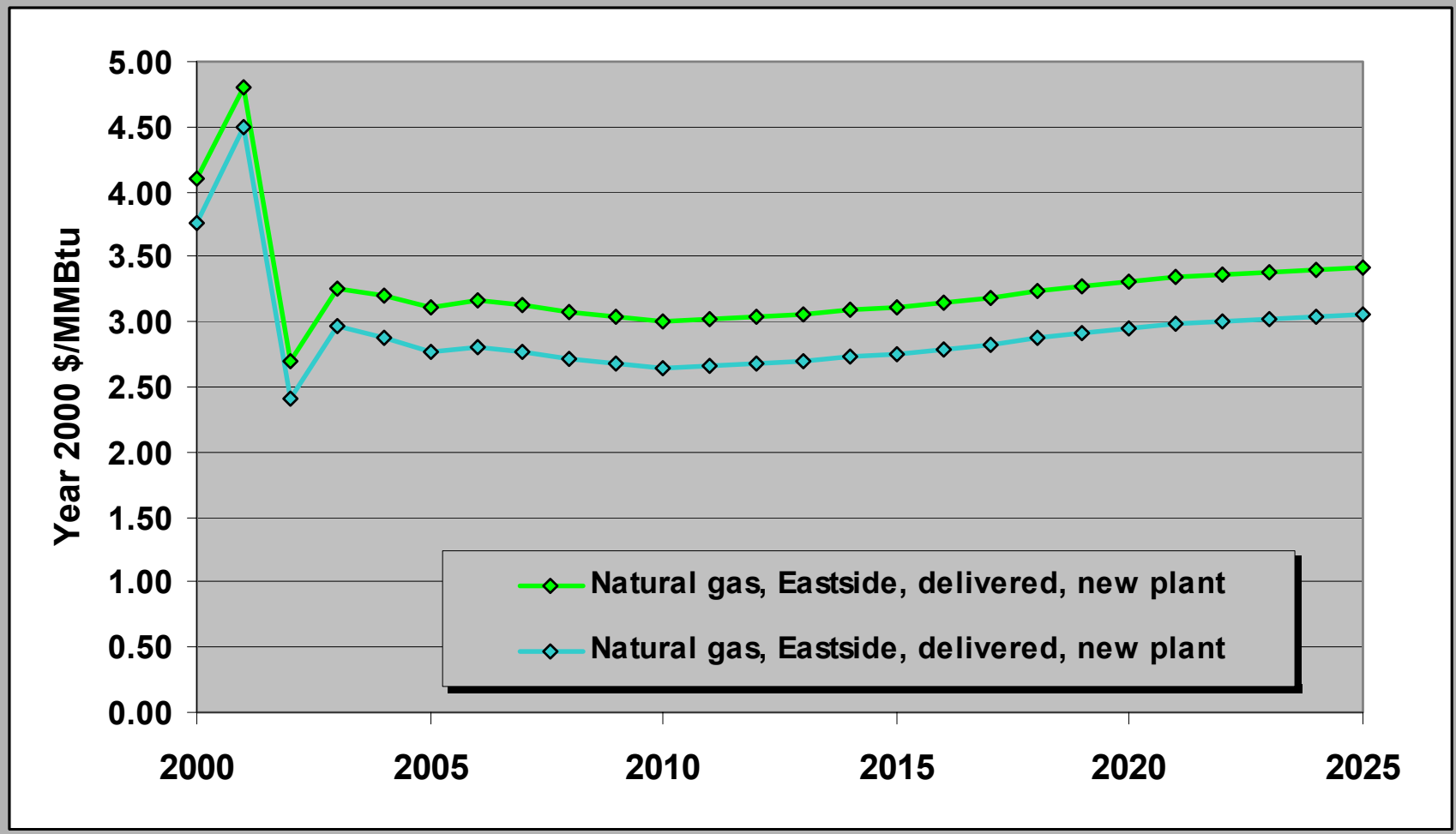
New resource characteristics 1

	Capital ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M ($/MWh)	Heat Rate, Lifecycle (Btu/kWh)	Technology Improvement (%/yr)
540 MW 2x1 CC	$565	$8.85 FOM $15 PtoP	$2.8	7030	Cost: -0.6% HR: -0.6%
70 MW Duct Firing	$225	$3 FOM $15 PtoP	$1	9500	Cost: +0.1% HR: -0.3%
2x46 MW SC	$730	$8 FOM $0 PtoP	$8	9960	Cost: -0.6% HR: -0.6%
100 MW Wind	$1010	$20 FOM $15 PtoP	B1: $1 + $4 IRR B2: $1 + $8 IRR	--	Cost:-4 >-2%
400 MW Coal Steam	$1230	$40 FOM $15 PtoP	$1.75 VOM	9550	Cost: +0.1% HR: -0.3%
20 MW Solar PV	$6000	$15 FOM $15 PtoP	Inc. in FOM	--	Cost:-8 >-4%

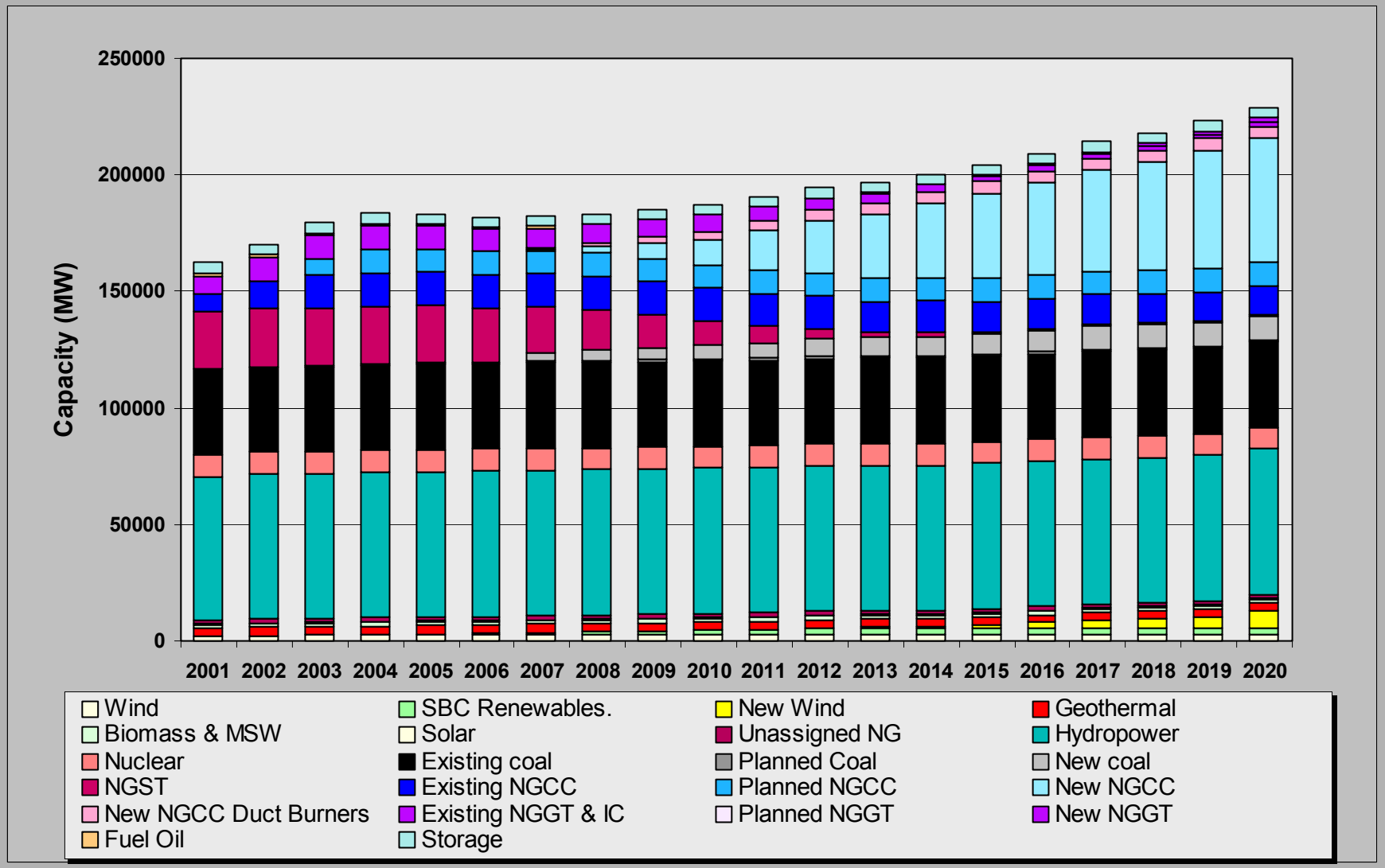
New resource characteristics 2

	Forced Outage (%)	Planned Outage (days/yr)	Availability (%)	Base Resource Limits	Developer Mix (COU/IOU/IPP)
540 MW 2x1 CC	5%	18	92%	Initially, not limited	15/15/70%
70 MW Duct Firing	5%	18	92%	Prior run new CC development	Same as new CC
2x46 MW SC	4%	10	94%	Initially, not limited	40/40/20%
100 MW Wind	Inc. in avail.	Inc. in avail.	B1: 28-36 % B2: 26-34%	B1: 1000MW/area B2: 2000MW/area	20/20/60%
400 MW Coal Steam	7%	35	84%	None in PNW West or CA	25/25/50%
20 MW Solar PV	Inc. in avail.	Inc. in avail.	22%	Not limited	50/25/25%

Selected fuel prices
(Medium case)



WECC Resource Mix



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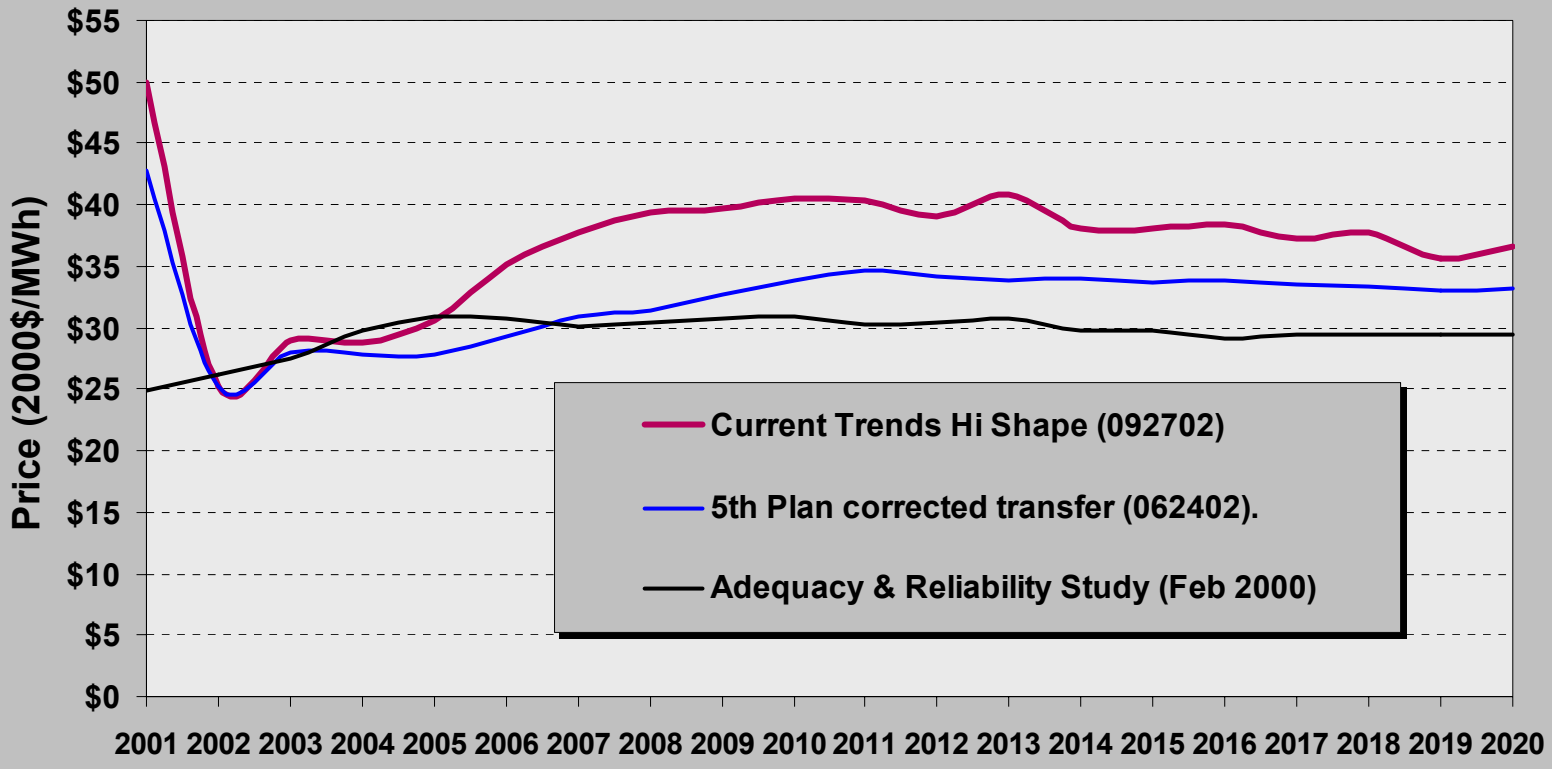
Mid-Columbia price forecast

Average annual w/comparisons

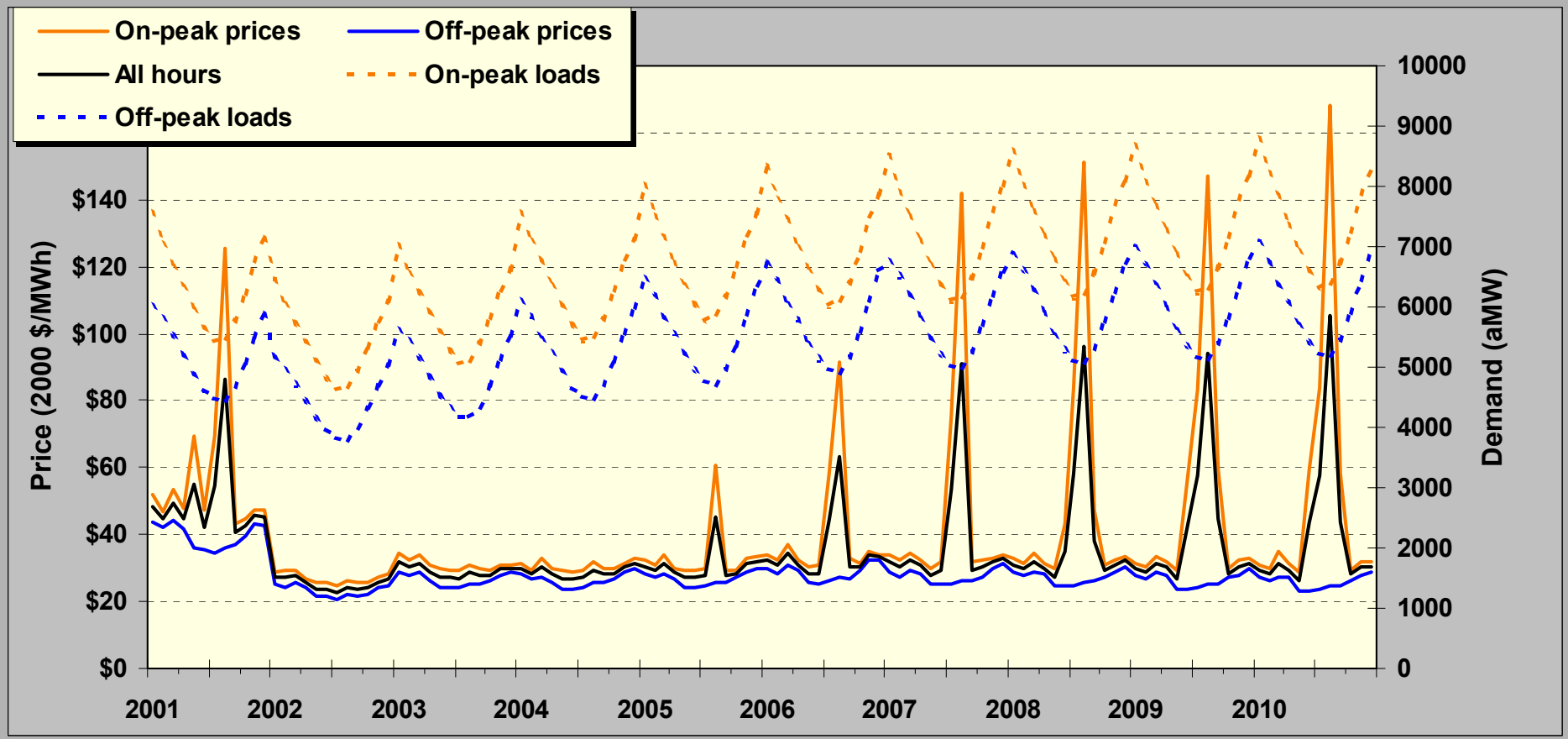


2002-20 Mid-Columbia price forecast

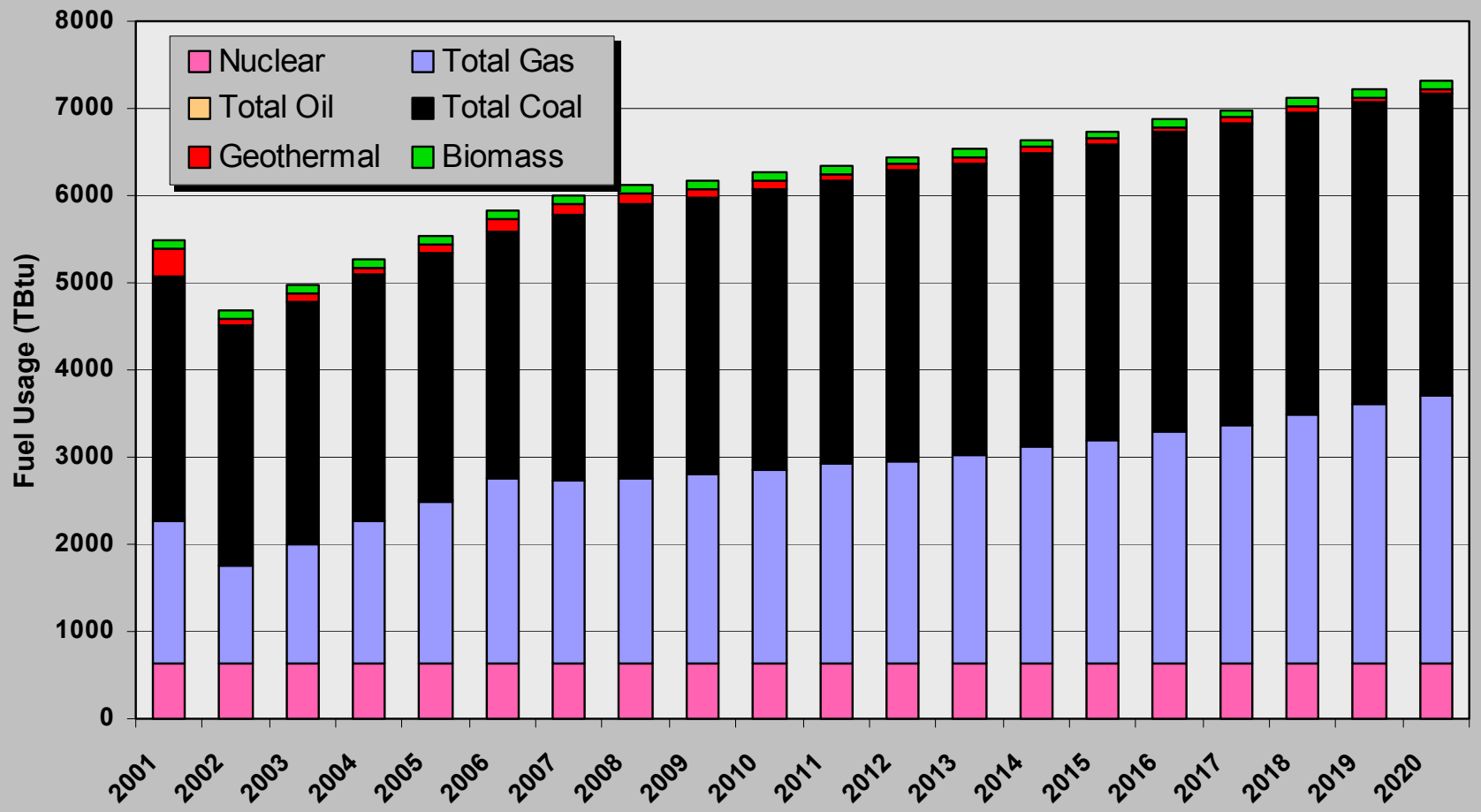
Levelized & compared to earlier forecasts

Mid-Columbia

2001-10 monthly average prices & loads



WECC Fuel Usage



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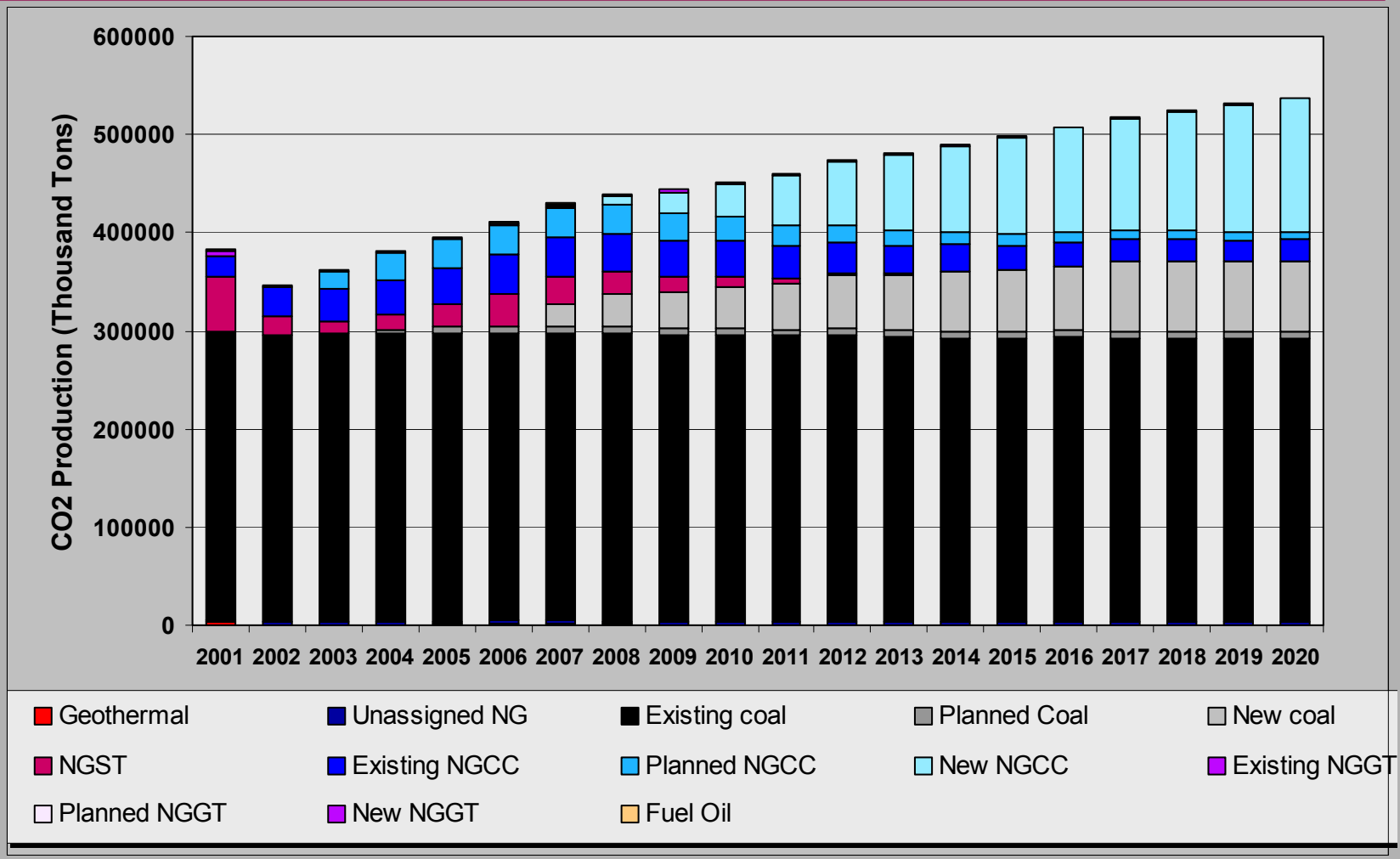
WECC CO2 Production

(Possible external offsets not shown)



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Base & sensitivity studies 1

	Lower Cost <	Current Trends	> Higher Cost
Fuel Prices	NPPC Low	NPPC Medium	NPPC High
Load Growth	NPPC Low	NPPC Medium	NPPC High
Renewable Incentives	Phaseout	$17 prod credit $7.50 tag SBC/RPS	$0.03/kWh (Declining w/CO2 control)
CO2 Control	None	Approx OR std: $1/Ton CO2, esc @ 20%/yr on 17% CO2	$15/TCO2 (test effect; attempt cap & trade model)
Clean Air Act	??	Hg control for new coal	??

Base & sensitivity studies 2

	Lower Cost <	**Current Trends**	**> Higher Cost**
Climate & Hydro	Test sensitivity to climate effects on hydrograph	Test sensitivity to climate effects on hydrograph	Test sensitivity to climate effects on hydrograph
Technology	Optimistic financing/impvmt.	Base	Pessimistic financing/impvmt.
Reliability	No operating reserve requirement	6.5% op. reserves, average water	6.5% op. reserves, critical water
Transmission congestion	Unfettered, rolled-in cost	Current plans	No expansion